Workshop on Multilateral and Extended Reach Wells

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- Sponsored by:
  - Minerals Management Service
  - Offshore Technology Research Center
- December 5, 2002
- New Orleans, Louisiana

Introductions

- Bjorn Gjorv, TAMU GAR
- Steve Walls, Cherokee Offshore Engineering
- Jerome Schubert, TAMU, PI

Outline

- **Introduction to Extended Reach and Multilateral Wells**
  - **Describe ERD and ML levels**
  - **Application**
- **Economic benefits**
  - **examples**

Outline, con't.

- **New drilling technologies that can enhance ML/ERD**
  - **Dual Gradient Drilling**
  - **Expandable tubulars**
  - **High lubricity muds**
  - **Hole cleaning**
  - **State of the art in ERD**
  - **State of the art in MLD**

Outline, con't.

- **Completion, workover, and fishing concepts**
  - **Horizontal gravel-packed sand control completions**
  - **Downhole completion tools for ER and ML wells**

Outline, con't.

- Technical difficulties
  - Lost circulation and other well control problems
  - Torque, drag, and buckling
  - Casing wear
  - Cementing
- Questions and discussion
- Adjourn

Introduction to Extended Reach and Multilateral Wells

- Describe ERD and ML wells

Wytch Farm

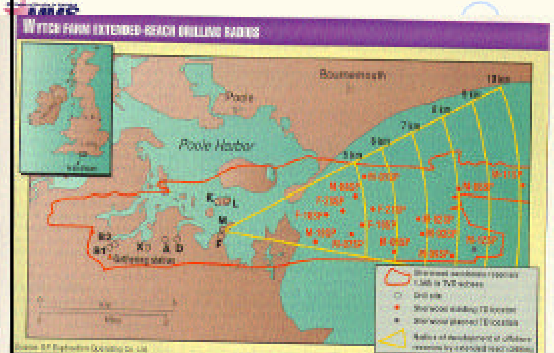
O&GJ, Jan. 19, 1998, p.24
SPE 28293 (1994)

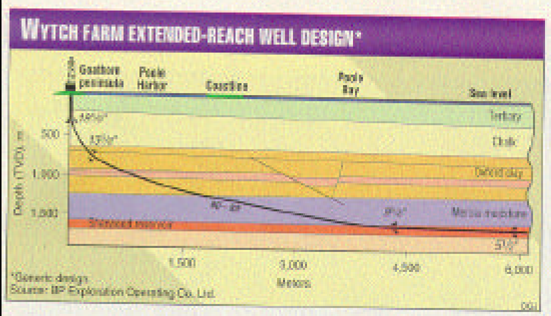
David Knott
Senior Editor

BP Exploration Operating Co. Ltd. completed a well in U.K. Wytch Farm oil field with a horizontal reach of 10.1 km, setting a world record.

The M-11 well was drilled from an onshore drill site into a reservoir that extends offshore and was brought into production on Jan. 12 at a rate of 20,000 b/d of oil.

REF: O&GJ, Jan. 19, 1998, p.24





Wytch Farm M11 Well

- Stepout (Horiz. Depart.) **= 33,181 ft**
- Exceeded previous record by 6,729 ft
- Measured Depth = 34,967 ft
- True Vertical Depth (at TD) = 5,266 ft
- Time to drill and case = 173 days
- M11 is the 14th ERD well at Wytch Farm

REF: Anadrill Press Release 1-23-98

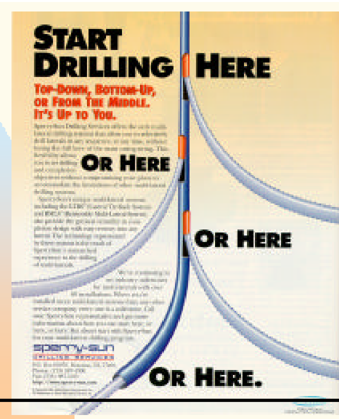
Overview cont'd

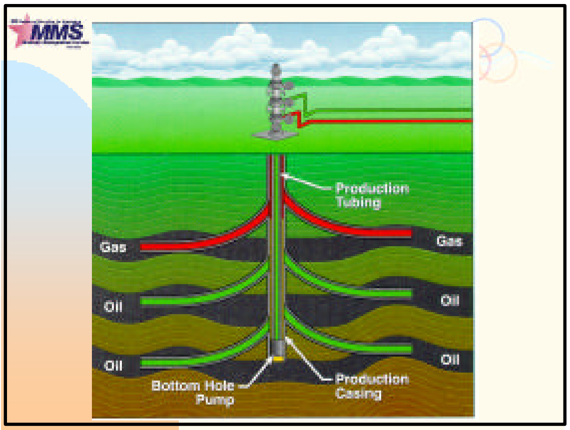
- One third of reserves are offshore under Poole Bay
- ERD project began in place of an artificial island in 1991
- Saved 150 million in development costs
- Development time saved - 3 years
- Scheduled with reach of 6.2 km
- Prod. before ERD project = 68,000 BOPD
- Prod. with 3 ERD wells = 90,000 BOPD

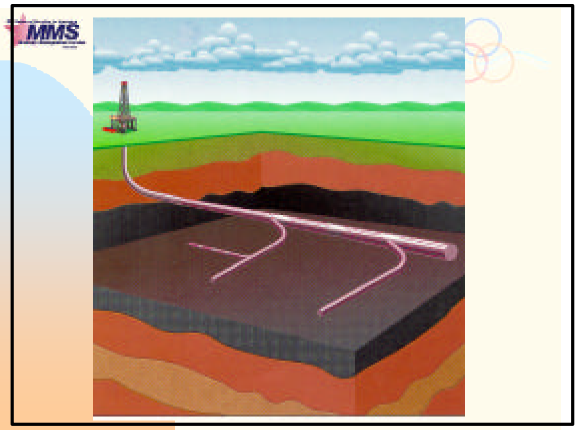
Multilaterals

Outline

- Figs. 3-6 Advertisements, PE Int.
- Figs. 7-9, OGJ, Dec. 11, 1995 p.44
- Figs. 10, 11, OGJ, March 16, 1998 p.76
- Figs. 12-17, OGJ, Dec. 1997, p.73
- Figs. 18-24, OGJ, March 23, 1998 p.70
- Oil & Gas Journal, Feb. 28, 2000, p.44




Production Tubing
Gas
Gas
Oil
Oil
Oil
Oil
Bottom Hole Pump
Production Casing



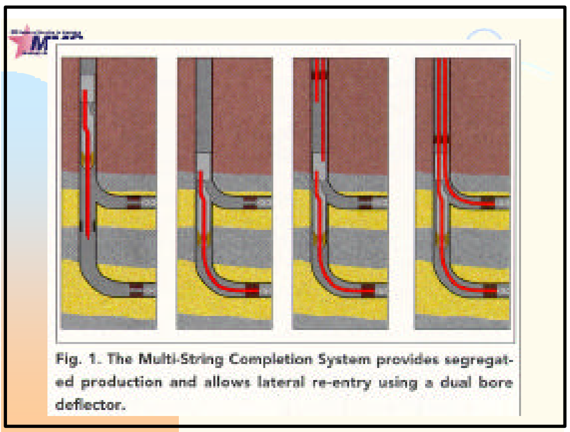
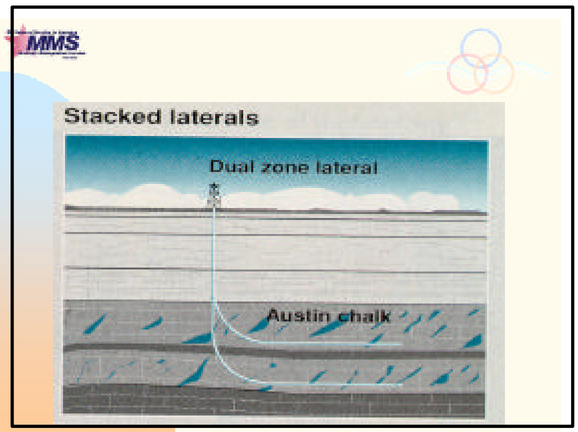
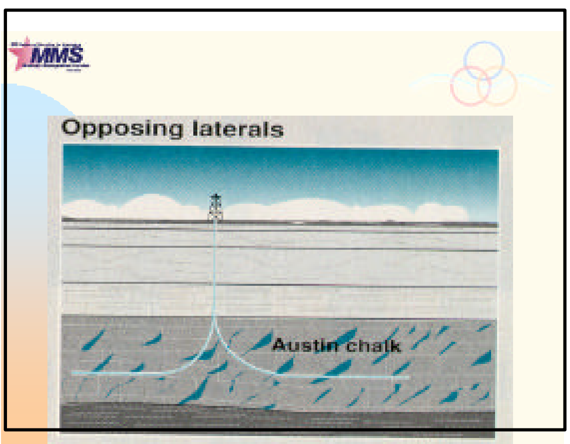
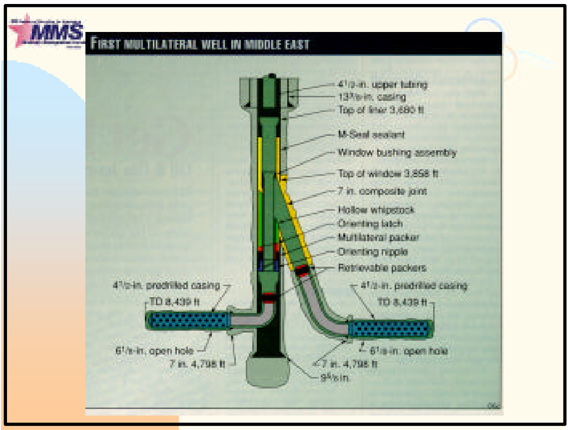


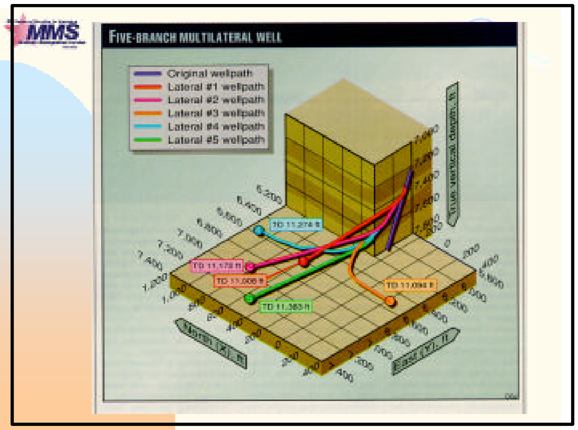
Fig. 1. The Multi-String Completion System provides segregated production and allows lateral re-entry using a dual bore deflector.

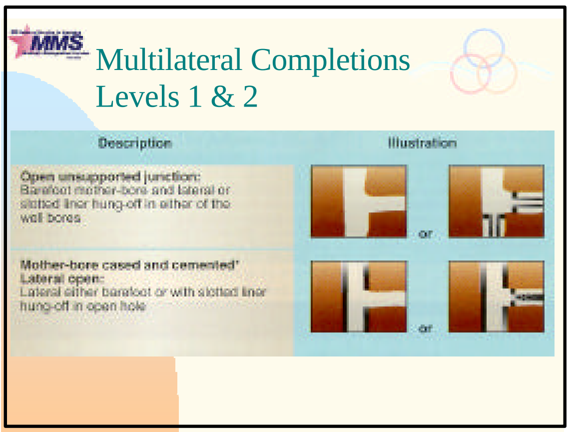

Stacked laterals
Dual zone lateral
Austin chalk

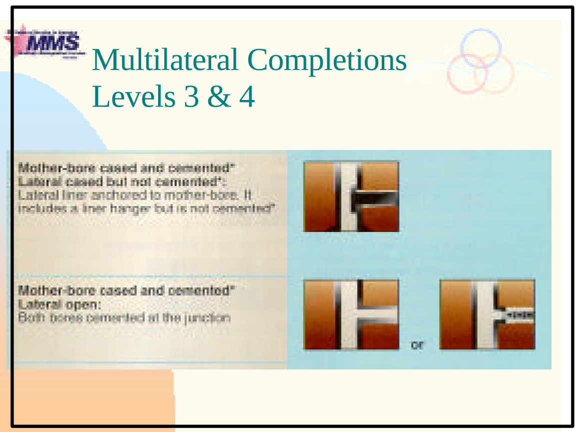

Opposing laterals
Austin chalk

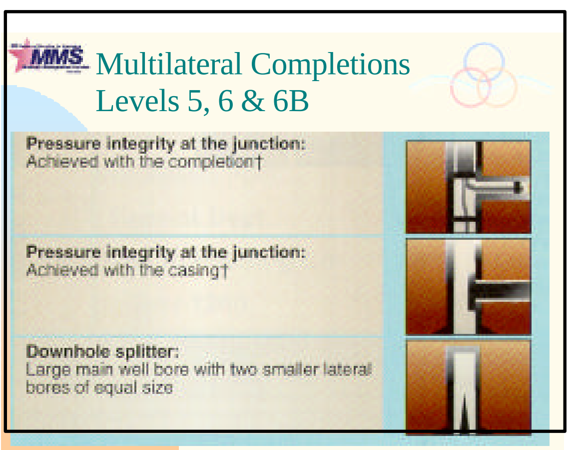

Retrievable whipstock
Retrievable whipstock
Austin chalk

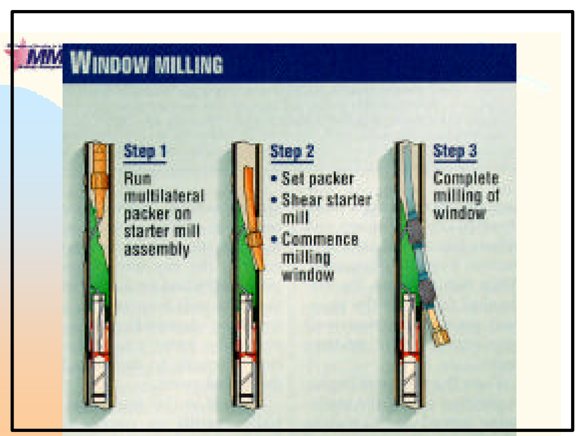

FIRST MULTILATERAL WELL IN MIDDLE EAST
4 1/2-in. upper tubing
13 3/8-in. casing
Top of liner 3,680 ft
M-Seal sealant
Window bushing assembly
Top of window 3,858 ft
7 in. composite joint
Hollow whipstock
Orienting latch
Multilateral packer
Orienting nipple
Retrievable packers
4 1/2-in. predrilled casing
TD 8,439 ft
4 1/2-in. predrilled casing
TD 8,439 ft
6 1/8-in. open hole
7 in. 4,798 ft
6 1/8-in. open hole
7 in. 4,798 ft
9 5/8 in.

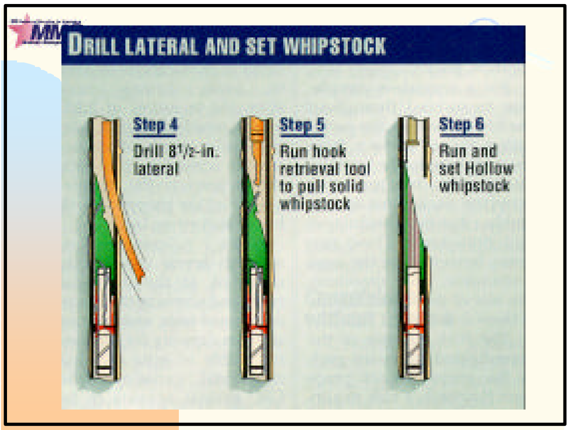

FIVE-BRANCH MULTILATERAL WELL
Original wellpath
Lateral #1 wellpath
Lateral #2 wellpath
Lateral #3 wellpath
Lateral #4 wellpath
Lateral #5 wellpath
TD 11,274 ft
TD 11,170 ft
TD 11,006 ft
TD 11,383 ft
TD 11,094 ft
True vertical depth, ft
North (X), ft
East (Y), ft

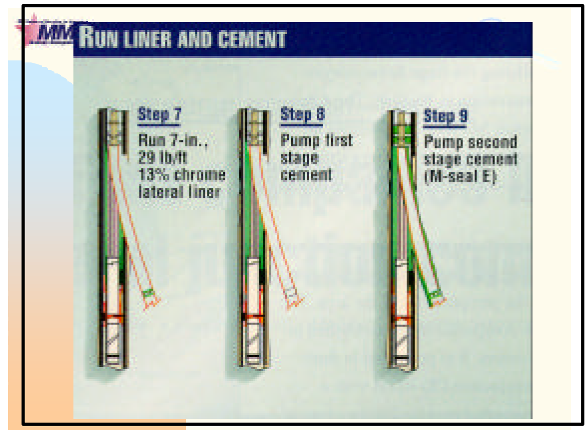

Multilateral Completions
Levels 1 & 2
Description
Illustration
Open unsupported junction:
Barefoot mother-bore and lateral or slotted liner hung-off in either of the well bores
or
Mother-bore cased and cemented*
Lateral open:
Lateral either barefoot or with slotted liner hung-off in open hole
or

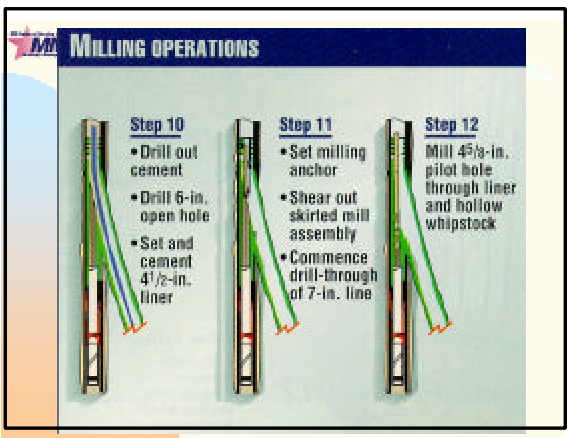

Multilateral Completions
Levels 3 & 4
Mother-bore cased and cemented*
Lateral cased but not cemented*:
Lateral liner anchored to mother-bore. It includes a liner hanger but is not cemented*
Mother-bore cased and cemented*
Lateral open:
Both bores cemented at the junction
or

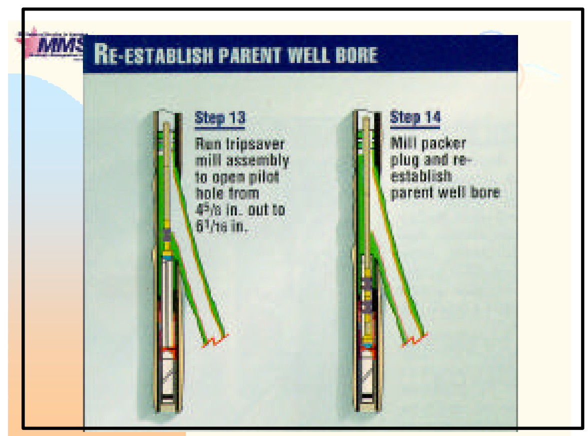

Multilateral Completions
Levels 5, 6 & 6B
Pressure integrity at the junction:
Achieved with the completion†
Pressure integrity at the junction:
Achieved with the casing†
Downhole splitter:
Large main well bore with two smaller lateral bores of equal size

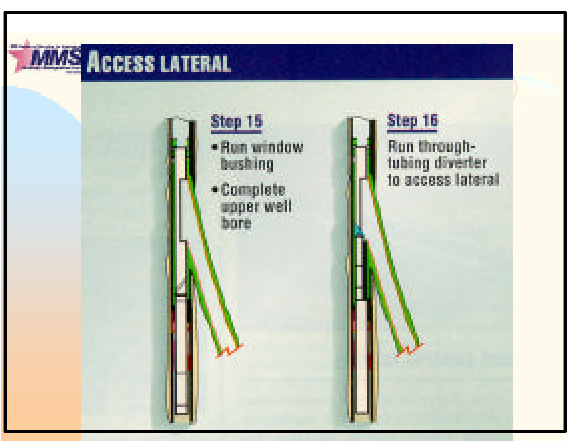

WINDOW MILLING
Step 1
Run multilateral packer on starter mill assembly
Step 2
• Set packer
• Shear starter mill
• Commence milling window
Step 3
Complete milling of window

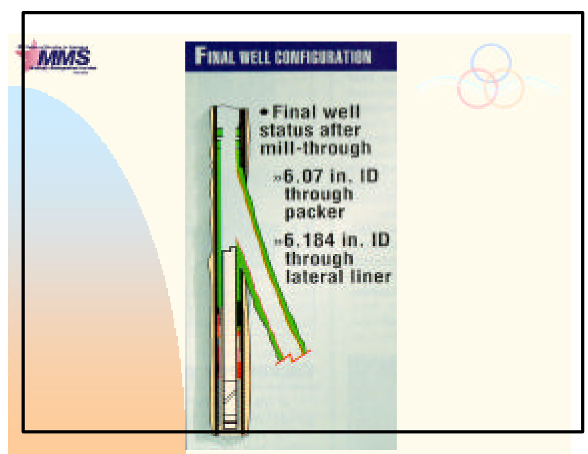

DRILL LATERAL AND SET WHIPSTOCK
Step 4
Drill 8 1/2-in. lateral
Step 5
Run hook retrieval tool to pull solid whipstock
Step 6
Run and set Hollow whipstock

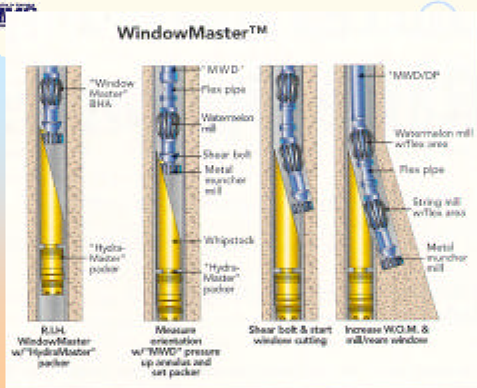

RUN LINER AND CEMENT
Step 7
Run 7-in., 29 lb/ft 13% chrome lateral liner
Step 8
Pump first stage cement
Step 9
Pump second stage cement (M-seal E)


MILLING OPERATIONS
Step 10
• Drill out cement
• Drill 6-in. open hole
• Set and cement 4 1/2-in. liner
Step 11
• Set milling anchor
• Shear out skirted mill assembly
• Commence drill-through of 7-in. line
Step 12
Mill 4 5/8-in. pilot hole through liner and hollow whipstock


RE-ESTABLISH PARENT WELL BORE
Step 13
Run tripsaver mill assembly to open pilot hole from 4 5/8 in. out to 6 1/16 in.
Step 14
Mill packer plug and re-establish parent well bore


ACCESS LATERAL
Step 15
• Run window bushing
• Complete upper well bore
Step 16
Run through-tubing diverter to access lateral


FINAL WELL CONFIGURATION
• Final well status after mill-through
» 6.07 in. ID through packer
» 6.184 in. ID through lateral liner



ERD/ML Applications

Attempt to reduce the cost per barrel of oil produced.
- Same or increased reservoir exposure with fewer wellbores

Substantial increase in drainage area.

Increased production per platform slot

ERD/ML Applications

- More reserves
- Production from natural fracture systems
- Efficient Reservoir drainage
- Exploiting reservoirs with vertical permeability barriers

ERD/ML Applications

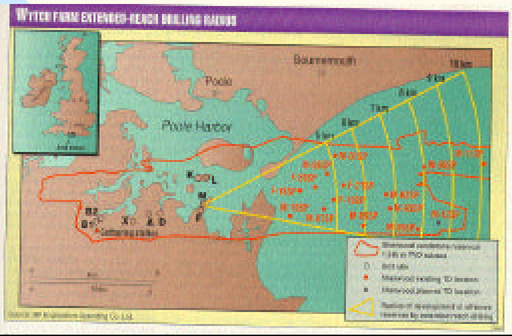
- Improving thin oil zone reservoirs production performance
- Increase ROI
- Reduce well cost
- Reduce time
- Reduce capital cost

ERD/ML Limitations

- Modeling of multilaterals
- Problems during production phase
- Increased cost compared to one conventional well
- Higher risk
- Technology still in development stage

Economic benefits

Wytch Farm

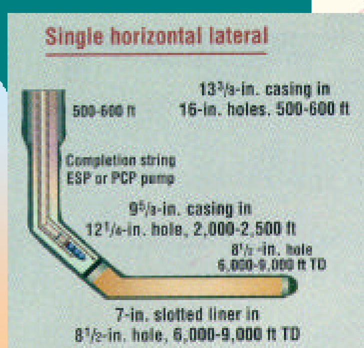


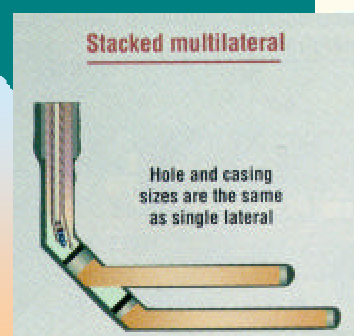
"Complex well geometries boost Orinoco heavy oil producing rates

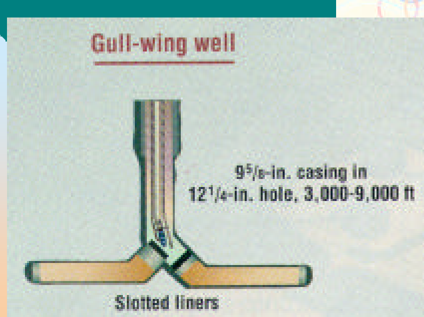
Oil & Gas Journal, Feb. 28, 2000

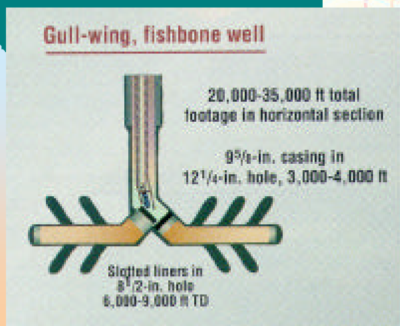
- Single horizontal lateral
- Gull-wing well
- Stacked multilateral
- Fishbone well
- Gull-wing, fishbone well
- Stacked fishbone well

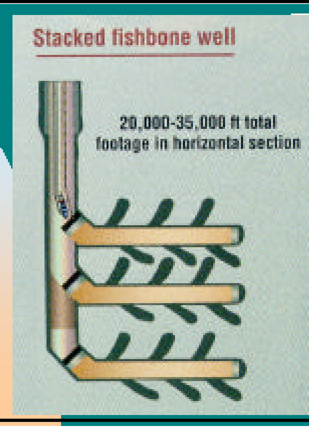
~9°API oil. ~1.2 * 10^{12} bbls in place. ~250 * 10^{9} recoverable

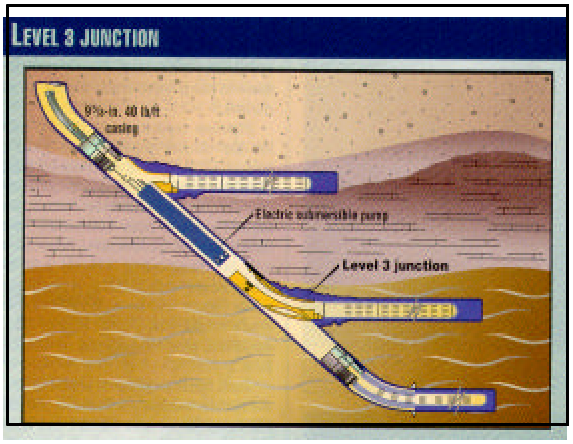












Unocal

- Dos Cuadras field – California
- Cost of a trilateral well - $2 million
- Cost of 3 conventional horizontals - $3 million

Texaco

- Brookeland field – Austin chalk
- Estimated savings of $500,000 - $700,000 per well as compared to two conventional horizontal wells of equivalent length

UPRC

- Austin Chalk – quadralateral
- Total cost for re-entry was $605,000 which is 20% less than the cost of two new dual lateral horizontals

Austin Chalk

- Changes from vertical to horizontal to ML led to reductions in development costs from $12/BOE to $5.75/BOE to $4.65/BOE

North Sea

- Reduced development costs by 23% and 44% respectively when horizontal and ML approaches are compared to vertical well development

Saih Rawl Shuaiba reservoir

- Dual lateral wells were drilled for water injection. Five wells completed successfully at 30% cost savings per dual well relative to two single laterals

Venezuela

- Level 3 Hook Hanger systems have yielded up to 900 bopd increase in production per well.
- Cost 1.58 times that of a single well
- But, Per-day increase in revenue, based on $20/bbl oil, is as much as $18,000/well

Deepwater Brazil

- ML costs an average of 1.43 times that of a single well
- While increased production, revenues and savings have amounted to as much as $10 million over conventional technology applied in the region

TFE - Argentina

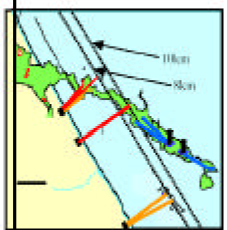


Fig. 1 Location of the Hidra field (Tierra del Fuego – Argentina)

	Capex	NPV	PayOT
Platform	2.3	1.9	5.8
Subsea	2	5.7	2.4
ERD	1	1	1

Table 1 – Comparaison between platform, subsae and ERD (Hidra – Argentina)

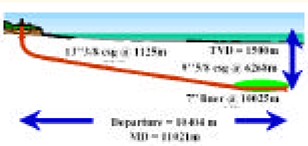
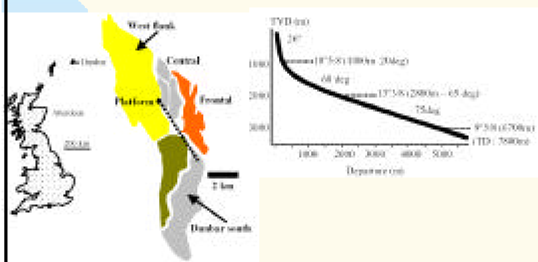


Fig. 2 ERD profile and casing strategy (Hidra field – Argentina – World record)

TFE – U.K.

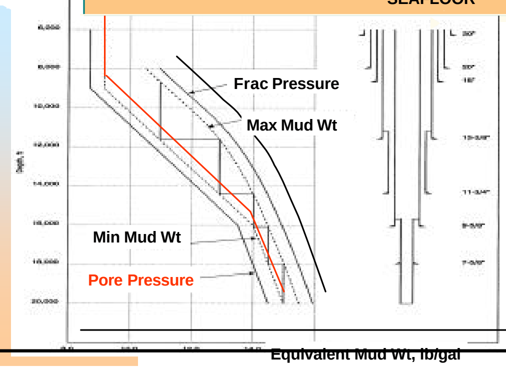


New drilling technologies that can enhance ML/ERD

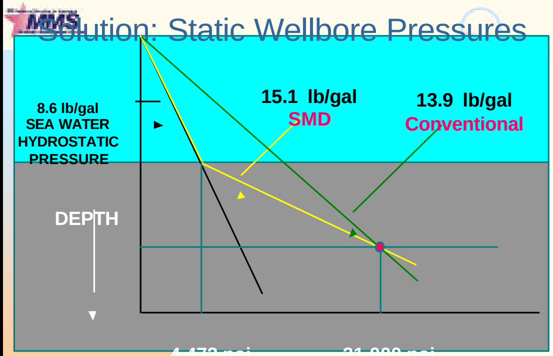
- Dual Gradient Drilling
- Expandable Liners
- High Lubricity Muds
- Hole Cleaning
- SOA in ERD and MLD

Dual Gradient Drilling

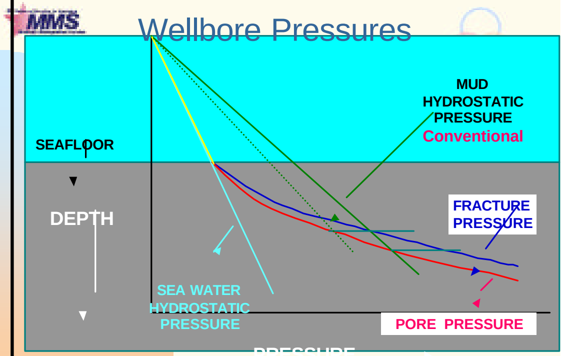
Conventional Casing Seat Selection

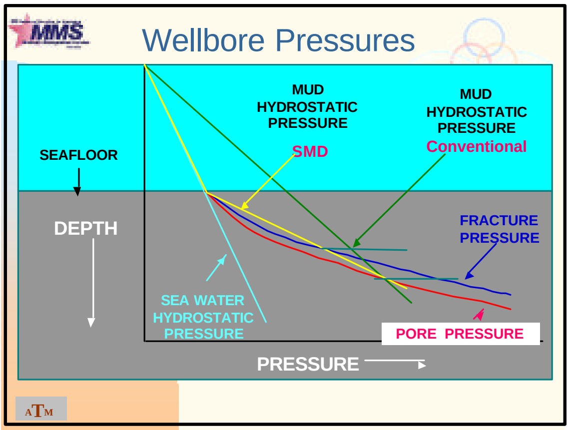


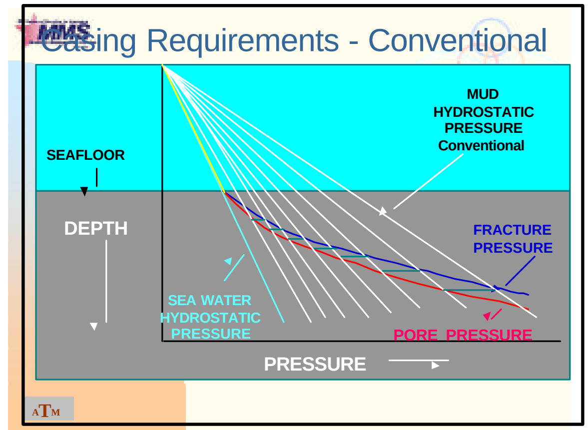
Solution: Static Wellbore Pressures

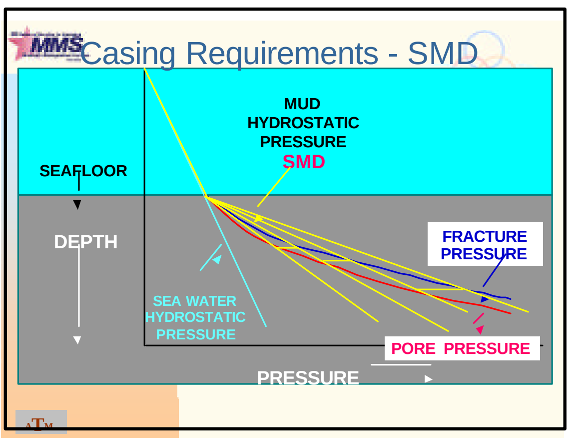


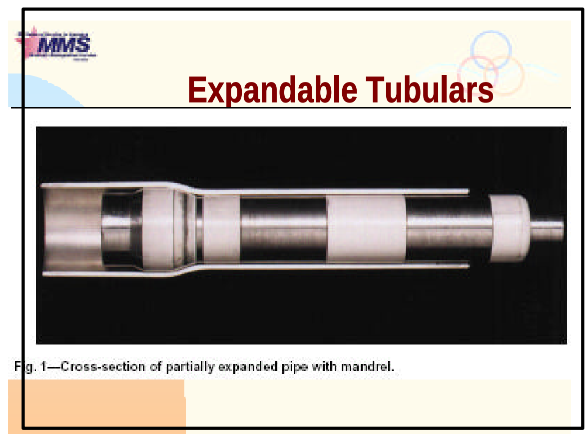
Wellbore Pressures

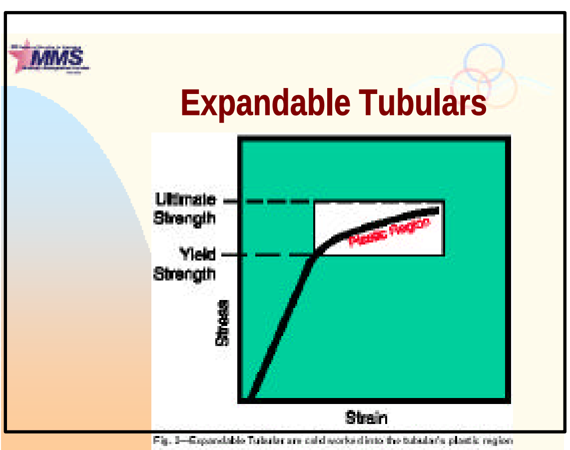


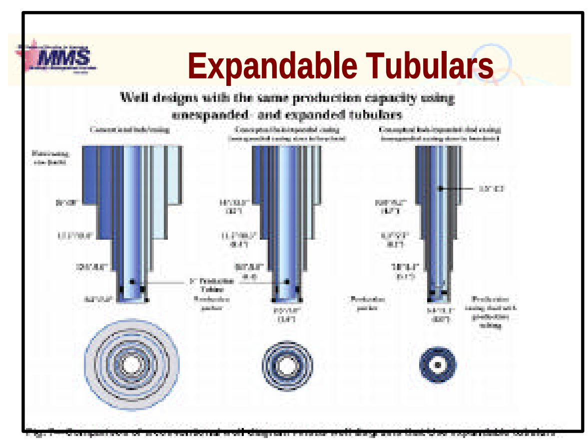

MMS
Wellbore Pressures
MUD
HYDROSTATIC
PRESSURE
SMD
MUD
HYDROSTATIC
PRESSURE
Conventional
SEAFLOOR
DEPTH
FRACTURE
PRESSURE
SEA WATER
HYDROSTATIC
PRESSURE
PORE PRESSURE
PRESSURE
ATM


MMS
Casing Requirements - Conventional
MUD
HYDROSTATIC
PRESSURE
Conventional
SEAFLOOR
DEPTH
FRACTURE
PRESSURE
SEA WATER
HYDROSTATIC
PRESSURE
PORE PRESSURE
PRESSURE
ATM


MMS
Casing Requirements - SMD
MUD
HYDROSTATIC
PRESSURE
SMD
SEAFLOOR
DEPTH
FRACTURE
PRESSURE
SEA WATER
HYDROSTATIC
PRESSURE
PORE PRESSURE
PRESSURE


MMS
Expandable Tubulars
Fig. 1—Cross-section of partially expanded pipe with mandrel.


MMS
Expandable Tubulars
Ultimate
Strength
Yield
Strength
Plastic Region
Stress
Strain
Fig. 3—Expandable Tubulars are cold worked into the tubular's plastic region


MMS
Expandable Tubulars
Well designs with the same production capacity using
unexpanded- and expanded tubulars

High lubricity muds

Hole cleaning

State of the art in ERD

State of the art in MLD

Completion, workover, and fishing concepts

Horizontal gravel-packed sand control completions

Downhole completion tools for ER and ML wells

Technical difficulties

- Lost Circulation
- Well Control Problems
- Torque, Drag, and Buckling
- Casing Wear
- Cementing

Lost circulation and other well control problems

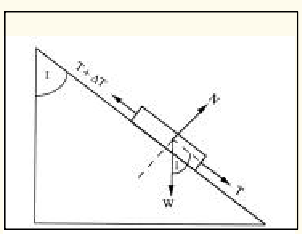
Steve Walls

Torque and Drag

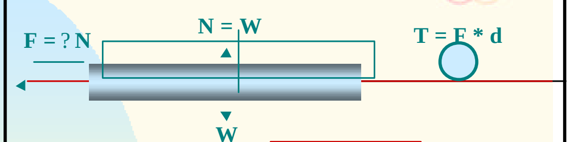
Sliding Motion

Drag (friction)

F = ? N = ? W sin I



Torque



Force to move pipe, F = ? W sin I

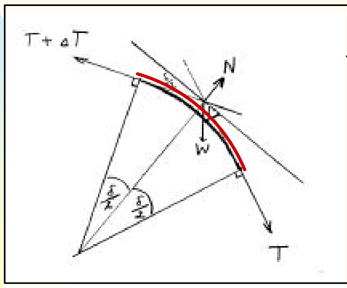
Torque, T = ? W sin I d/(24)

An approximate equation, with W in lbf and d in inches

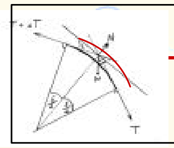
Effect of Doglegs

(1) Dropoff Wellbore

? ? dogleg angle



Effect of Doglegs



A. Neglecting Axial Friction
pipe rotating)

$$N \; ? \; W\sin I \; ? \; 2T\sin\frac{?}{2} \qquad (10)$$

Effect of Doglegs

$$\text{Torque} \; ? \; ?N?\frac{d}{2}?? \; ? \; ?\frac{d}{2}?(W\sin I \; ? \; 2T\sin\frac{?}{2})$$

Buckling

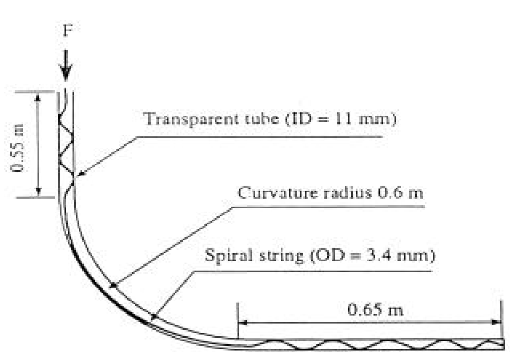


Figure 7 Schematic view of the small scale test loop

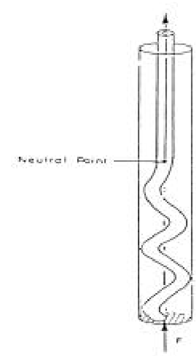


Fig 2 A schematic for coiled tubing buckling in a vertical wellbore

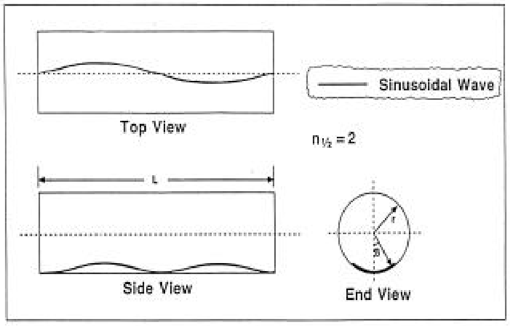


Fig. 1—Postbuckled configuration of pipe in a horizontal hole.

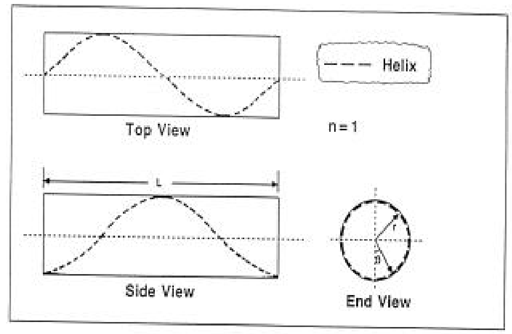
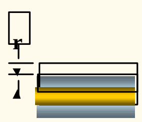


Fig. 1—Postbuckled configuration of pipe in a horizontal hole.

Sinusoidal Buckling in a Horizontal Wellbore

When the axial compressive load along the coiled tubing reaches the following sinusoidal buckling load F_{cr}, the intial (sinusoidal or critical) buckling of the coiled tube will occur in the horizontal wellbore.

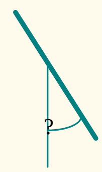
$$F_{cr} ? 2(EIW_e/r)^{0.5}$$



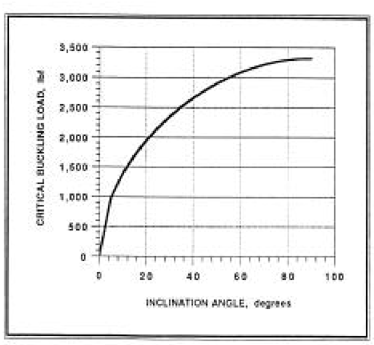
Sinusoidal Buckling Load

A more general Sinusoidal Buckling Load equation for highly inclined wellbores (including the horizontal wellbore) is:

$$F_{cr} ? 2\sqrt{\frac{EIW_e \sin ?}{r}}$$



Deg	Fcr
0	0
5.00	979
10.00	1,382
15.00	1,688
20.00	1,940
25.00	2,157
30.00	2,348
35.00	2,512
40.00	2,660
45.00	2,789
50.00	2,903
55.00	3,002
60.00	3,087
65.00	3,158
70.00	3,216
75.00	3,260
80.00	3,292
85.00	3,311
90.00	3,317



Helical Buckling in a Horizontal Wellbore

When the axial compressive load reaches the following helical buckling load F_{hel} in the horizontal wellbore, the helical buckling of coiled tubing then occurs:

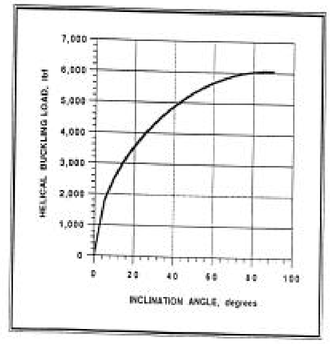
$$F_{hel} ? 2 ?2\sqrt{2} ? 1? \sqrt{\frac{EIW_e}{r}}$$

General Equation

A more general helical buckling load equation for highly inclined wellbores (including the horizontal wellbore) is:

$$F_{hel} ? 2 ?2\sqrt{2} ? 1? \sqrt{\frac{EIW_e \sin ?}{r}}$$

Deg	Fhel
D	d
5.00	1,791
10.00	2,527
15.00	3,086
20.00	3,547
25.00	3,943
30.00	4,289
35.00	4,594
40.00	4,863
45.00	5,100
50.00	5,309
55.00	5,490
60.00	5,644
65.00	5,774
70.00	5,880
75.00	5,961
80.00	6,019
85.00	6,054
90.00	6,065



Buckling in Vertical Wellbores:

In a vertical wellbore, the buckling will occur if the tubulars becomes axially compressed and the axial compressive load exceeds the buckling load in the vertical section.

This could happen when we “slack-off” weight at the surface to apply bit weight for drilling and **pushing** the coiled tubing through the build section and into the horizontal section.

Helical Buckling in Vertical Wellbores:

A helical buckling load for weighty tubulars in vertical wellbores was also derived recently through an energy analysis to predict the occurrence of the helical buckling:

$$F_{hel,b} ? 5.55 (EIW_e^{\ 2})^{1/3}$$

Helical Buckling in Vertical Wellbores:

This helical buckling load predicts the first occurrence of helical buckling of the weighty tubulars in the vertical wellbore.

The first occurrence of helical buckling in the vertical wellbore will be a one-pitch helical buckle at the bottom portion of the tubular, immediately above the KOP.

Helical Buckling in Vertical Wellbores:

The upper portion of the tubular in the vertical wellbore will be in tension and remain straight.

When more tubular weight is slacked-off at the surface, and the helical buckling becomes more than one helical pitch, the above helical buckling load equation may be used for **the top helical pitch** of the helically buckled tubular.

Helical Buckling in Vertical Wellbores:

The top helical buckling load $F_{hel,t}$ is calculated by simply subtracting the tubular weight of the initial one-pitch of helically buckled pipe from the helical buckling load $F_{hel,b}$, which is defined at the bottom of the one-pitch helically buckled tubular:

$$F_{hel,t} \; ? \; 5.55(EIW_e^{\,2})^{1/3} \; ? \; W_e L_{hel}$$

$$? \; 0.14(EIW_e^{\,2})^{1/3}$$

Helical Buckling in Vertical Wellbores:

From Table 1, it is also amazing to find out that the top helical buckling load, $F_{hel,t}$, is very close to zero.

This indicates that the "neutral point", which is defined as the place of zero axial load (effective axial load exclusive from the hydrostatic pressure force), could be approximately used to define the top of the helical buckling for these coiled tubings.

Conclusions

1. When conducting drilling, well completion and wireline logging in horizontal wells using CT, helical buckling of the tubing in the vertical section of the horizontal wells will usually happen. How to reduce this buckling will be a significant challenge in developing and extending CT technology for horizontal wells.

Continue ...

2. The CT may buckle helically in the horizontal section when conducting the above operations, but it is seldom for the CT to buckle in the build section of a horizontal well.

Continue ...

3. The axial load distribution of helically buckled CT will be largely affected by the frictional drag generated by the helical buckling.

The CT may be "locked-up" in a horizontal well when a large portion of CT is helically buckled, to the point where you can hardly increase the bottom load, such as the bit weight, by "slacking-off" weight at the surface, nor push the CT further into the wellbore.

Continue ...

4. The equations on tubular buckling and axial load distributions presented here make it possible to predict the actual bit weight/packer load, and the maximum horizontal section length, for drilling, well completion, CT wire logging, CT stimulation, and other CT operations in horizontal wells. Generally, larger size of CT will reduce the risk of helical buckling and the amount of resulting frictional drag.

Casing wear

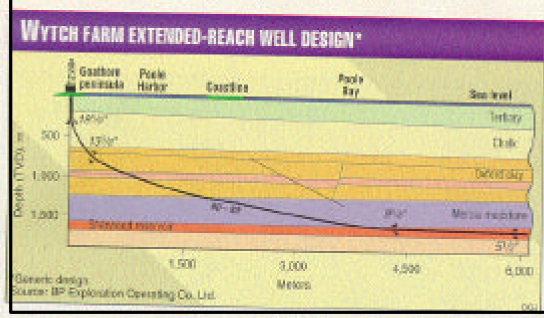
Excess torque and drag

- Threaten the success of completion if it exceeds the capacity of the Drive system or drillstring.
- Can result in casing wear

Excess torque and drag

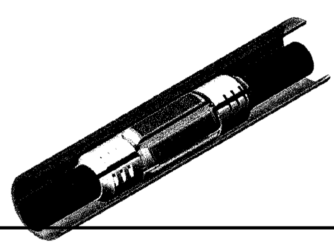
- Can be prevented or reduced.
  - Wellbore profile.
    - Low doglegs
    - Catenary profile
  - High lubricity muds
  - Non-rotating drillpipe protectors
  - Rotary steerable systems

Catenary wellbore



Non-rotating drillpipe protectors

Figure 1: 3-1/2" Low-Drag NRDPP Inside 7" Casing

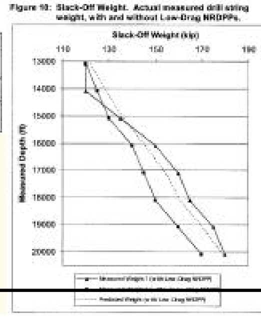


Non-rotating drillpipe protectors

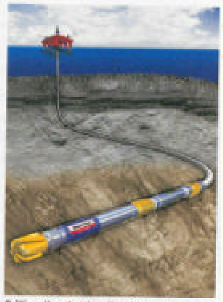
Table 1: Average Rotational and Sliding COF's.

RESULTS	Low Drag NRDPP	Bare Drill Pipe
Average Sliding COF	0.11	0.21
Average Rotational COF	0.03	0.20

Figure 10: Slack-Off Weight. Actual measured drill string weight, with and without Low-Drag NRDPPs.



Rotary Steerable Systems



Drilling directional wells with a rotary steerable system results in a smoother wellbore. This results from constant rotation and deflecting the drillstring through adjustments downhole. Halliburton's Geo-Pilot system is depicted above.

Remediation for Casing Wear

- Retrieve and replace
- Scab liners (tie back)
- Plastic liners
- Expandable cased-hole liners

Plastic Liners

Fig. 1. Roller reduction application places a tight-fit liner into the well. Reel capacity varies with liner diameter, and can be 5,000 to 12,000 ft of coiled plastic liner.

Plastic Liners

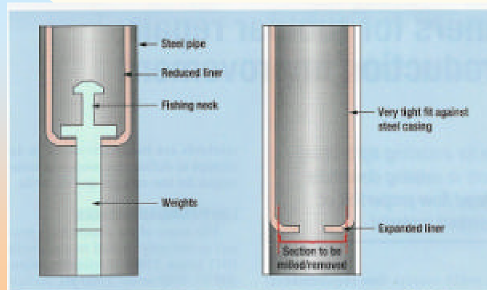


Fig. 2. Following downsizing, plastic liner is pulled into the well with simple weights that are retrieved through the liner bore after target depth is reached. After weights are removed, liner "memory" takes over and the plastic grows out against the steel pipe.

Plastic Liners

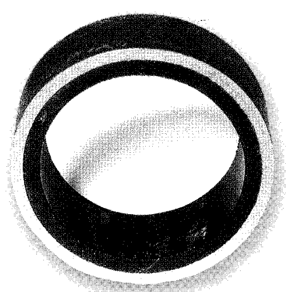


Fig. 3. As this sample pipe cross-section shows, a properly selected plastic, accurately downsized and successfully fitted, provides a tight-fitting liner that pushes out against the steel with a force that requires about 100 lb/in. to move; i.e., the liner is self-hanging.

Solid Expandable Tubulars

Fig. 1. Early expansion cone used to expand solid expandable tubulars.

Cementing

Variables that affect liner cementing performance in deviated wellbores

Cementing

- Displacement flow rate
- Cement slurry rheology
- Turbulators placement
- Centralization

Displacement flow rate

- Prodhoe Bay wells
  - 8-1/2” x 7” liner
    - Circulate at a velocity of 420-540 ft/min
  - 6-6/4” x 5-1/2” liner
    - Circulate at 600 ft/min
  - Cement slurry was displaced at 12 BPM

Cement slurry rheology

- Field results show more success with thinner cement slurries.
- This allow turbulent flow
- PV of 30-40
- YP of 3-5
- Results in a maximum swirl and turbulence

Turbulators placement

- Short 5 inch cylinders with spiral rigid vanes welded and positioned at approximately 30-45 deg.
- Forces the fluid to flow in a spiral pattern around the casing and wellbore.
- Two per joint is usually good
- Point in same direction

Centralization

- Must have enough centralizers to support the casing to centralize properly

Critical ERD Technologies

SPE 28293 (1994)

- Critical Technologies for Success in Extended Reach Drilling (ERD) by Payne, M.L., Cocking, D.A., and Hatch, A.J.
- Presented at the SPE ATCE, 1994, NO

Outline

- This paper discusses critical technologies for ERD.
  - Torque/drag
  - Drillstring design
  - Wellbore stability
  - Hole cleaning . . .

Outline - cont'd

  - Casing considerations
  - Directional drilling optimization
  - Drilling dynamics
  - Rig sizing
- This paper is based on knowledge and experience gained from Wytch ERD project

Torque/Drag

- Optimization of directional profile
- Mud lubricity
- Torque reduction tools
- Modeling considerations

Optimization of directional profile

- Simple build and hold profile is not successful
  - High torque and drag
  - BUR = 4 deg./30 m from near surface

Directional profile - cont'd

- Pseudo-catenary profile is used
  - Initial BUR = 1.0 - 1.5 deg./30 m
  - Maximum BUR = 2.5 deg./30 m
  - BUR increase = 0.5 deg./400 m
  - Target angle = 80 - 82 deg.
  - Torque reduction
  - Easy to run or slide drilling assemblies

Mud lubricity

- It is important but complex.
- It affect torque and drag.
- WBM is used in the beginning
- OBM is used after setting 13-3/8 in. casing
- Oil-water ratio has a significant impact on lubricity - **more oil => less friction**

Torque reduction tools

- Non-rotating DP protectors
  - Typically one on every other joint
  - Reduced torque ~ 25%
- Lubricating beads
  - Expensive for OBM
  - Reduced torque ~ 15%

Modeling considerations

- No torque/drag model is adequate for dynamic drilling conditions
- Use MWD sub to measure downhole torque on bit and WOB
- Using MWD data, estimate friction coefficients to monitor and to predict downhole conditions such as torque/drag, wellbore stability, and hole cleaning

Drillstring design

- Top-drive rotary system capacity = 45 - 60 kips-ft
- Useful only if the drillstring provides matching strength

Drillstring design for high torsional capacity

- Grade S-135 is conventional
- Grades up to 165 ksi are considered non-conventional and "high strength"
- High torque thread compounds
- High torque connections
  - Double-shoulder tool-joints
  - Wedge thread tool-joints

Hole stability for high hole inclination

- Use correct mud weight
- Stress data from:
  - Leak-off test
  - Extensometer
  - 4-arm calipers
- Chemical interactions between mud and formation also affect stability

Hole cleaning

- Flowrate is the primary hole cleaning tool - up to 1,100 gpm in the 12 1/4" hole
- Rheology
- Pipe Rotation
- Circulate cuttings out - prior to trip
- Monitoring of hole cleaning

Solids control

- Solids control in mud is essential for long MD holes where hole cleaning efficiency may tend to be low
- May need extra processes or equipments

Casing consideration

- Casing wear avoidance
  - Tungsten carbide protects the drillpipe well, but is hard in casing
  - Use of new generation of hard-metal, e.g. chromium-based metals
  - Use of alternative hard-facing materials
- Several casing running options

Casing running options

- Three primary considerations
  - Maximum available running weight
  - Frictional losses of running weight
  - Mechanical losses of running weight

Directional well planning

- Anti-collision considerations
  - It is necessary when well separation is small.
- Target sizing (ex. 200 m by 350 m)
- Profile planning (ex. pseudo-catenary profile)

Hydraulic consideration

- Proper selection of PDM rotor nozzles
- Bit nozzle selection
  - Maximum bit pressure drop of 500 psi

BHA philosophy

- Change of one "primary" BHA component at a time.
- Use of steerable PDMs.
- Development of solid relationships with bit manufacturers and advancement of bit designs with those of the BHA.

Tortuousity considerations (dog-leg severity)

- Need to minimize slide interval and frequency
  - Slide on 5-7 m increments to maintain low angular change

Emerging technologies

- Rotary-steerable system
- Azimuth control tool

Surveying

- MWD
- Gyro surveys for specific objectives:
  - Anti-collision requirements
  - To reduce lateral errors at target entry
  - Definitive survey at target entry

Drilling dynamics

- Torsional stick/slip vibrations cause chaotic bit and drillstring motion and adversely affect bit life, ROP, and rotary drilling capacity
- Rotary feedback system to reduce torsional vibrations
- Bit/BHA induced lateral vibrations
- Hole Spiral

Rig sizing

- Requirements depend on ERD project size.
- Proper rig and drilling equipment is critical.
- It is necessary to determine maximum anticipated drilling torques and margins.
- Rig power efficiency must be analyzed.

Conclusions

- Special rig configurations and drilling equipments are necessary to successfully pursue extreme ERD objectives.

Conclusions cont'd

- ERD operations require intense engineering focus on monitoring and analysis of field data and forecasting on future wells.
- High levels of team-based performance can be critical to ERD success.

Questions and discussion

The End

Thank you